QUANTIFYING CHANGES IN RETAIL ELECTRICITY RATES RESULTING FROM A MICROGRID DEPLOYMENT

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A capstone project submitted to Johns Hopkins University in conformity with the requirements for the degree of Master of Science in Energy Policy and Climate

Baltimore, Maryland
December, 2017

Executive Summary

Understanding how a proposed microgrid would affect customers is critical to deciding whether to deploy such a system and this paper seeks to assess how a microgrid deployment would affect retail electricity rates for residents of Cape Hatteras, North Carolina.

To answer this question, a simplified model was first developed and then run using inputs specific to Cape Hatteras imagining a microgrid system with local distributed generation. The results of the modeling suggest that average retail electricity rates, in $/kWh, will increase slightly during winter months but decrease slightly during the summer. Additionally, annual electricity bills for Cape Hatteras residents can be expected to decrease by an average of $114.14 per year.

The results of the modeling also suggest a -21% rate of return to the local co-op for the overall project and all individual project segments apart from the demand response initiative. However, project rate of return is heavily dependent on the frequency and severity of major outages. Additionally, microgrid designs are highly customizable for use with different technologies and government policy can play a significant role in ensuring economic viability of a microgrid paired with distributed generation. In all, a holistic review suggests there is the potential for an economically-viable microgrid deployment on Cape Hatteras, NC.

The completion of this project enabled me to synthesize the various topics of learning throughout the EPC program. I was able to apply my knowledge of finance, the technical aspects of different energy technologies, and created the potential for policy integration to test the real-world effects of different policies. During the completion of this project, I also gained more insight into renewable project financing for energy cooperatives, community cooperative operations in general, and an appreciation for energy efficiency and grid modernization efforts currently underway at local levels.

Acknowledgements

I would like to express my gratitude to my project mentor, Peter Saundry, Adjunct Faculty at Johns Hopkins AAP and Senior Fellow at the National Council for Science and the Environment (NCSE), for his assistance in helping me complete this project. His guidance was instrumental in shaping the direction of the paper and his technical expertise was critical in guiding my thinking.

I would also like to extend my appreciation to George Price, Manager of Engineering and Operations at Cape Hatteras Electric Cooperative (CHEC), for his willingness to help me understand the role of CHEC and the current initiatives the community is undertaking. His willingness to share data provided crucial inputs for the model, without which would have made completing this project much more difficult.

Finally, I would like to thank Dan Zachary, Director of the Energy Policy and Climate program at Johns Hopkins AAP, for his guidance and support throughout the semester.

Table of Contents

List of Acronyms

CHEC	Cape Hatteras Electric Cooperative
EIA	Energy Information Administration
EPRI	Electric Power Research Institute
GW	Gigawatt
kW	Kilowatt
kWh	Kilowatt-hour
LCOE	Levelized Cost of Energy
LCOS	Levelized Cost of Storage
LMP	Locational Marginal Price
MW	Megawatt
NCEMC	North Carolina Electric Membership Corporation
NREL	National Renewable Energy Laboratory
NYSERDA	New York State Energy Research and Development Authority
O&M	Operations and Maintenance
PJM	Pennsylvania-New Jersey-Maryland Interconnection
ppm	Parts per million
PV	Photovoltaic

List of Tables and Figures

1. Introduction

Microgrids are localized electricity distribution systems containing loads and distributed energy resources (such as distributed generation, storage, and demand response) that are actively managed in a controlled, coordinated way either while connected to the main power grid or while operating independently in “islanded” mode.[1] This islanding capability significantly improves reliability by limiting the impact of a disruption on the macrogrid.

In addition to increasing grid reliability, microgrids offer improved resiliency enabling faster adaptation and response to extreme weather events and natural disasters. More intense storms resulting from our changing climate raise the prospect of more widespread, regional disruptions of power.[2] Therefore, it is essential that our electricity delivery system can actively respond to and minimize at a local level the impact of any prolonged outage. Microgrids are a tool to develop that capability.

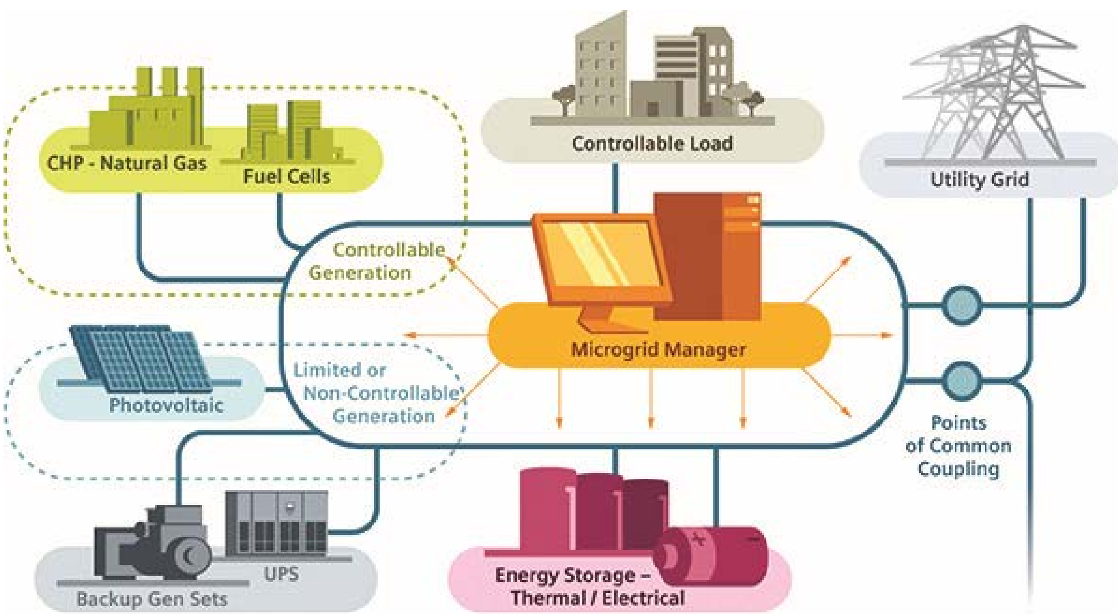

Figure 1. Schematic showing the basic overview of a microgrid system.[35]

Interest in microgrids is growing, with installed capacity projected to increase 115% to 4.3 GW by 2021 compared to 2016 levels,[3] but until recently, they have primarily served a role in supporting critical infrastructure such as hospitals and first responder stations. However, in the aftermath of Superstorm Sandy, communities began recognizing the value of microgrids for residential uses as well. Microgrids also present an opportunity to integrate more renewable generation into the grid helping cities and states meet emissions-reduction and climate goals.

Roughly 6% of electricity is lost annually during transmission and distribution in the United States,[4] or enough to power the state of Florida for a year.[5] Considering microgrids are highly localized systems, they can also improve grid efficiency by reducing the distance between generation and load.

While microgrids are sometimes viewed as an insurance measure, there are additional financial incentives available, particularly for remote communities. From Alaskan villages to isolated desert towns in California, microgrids are becoming an increasingly appealing option to reduce transmission costs and natural gas/diesel costs for onsite generation. Increasing renewable onsite generation capacity for these communities also serves to diversify the electricity supply and limit dependence on a single transmission line or fuel shipment to provide power.

A worst-case scenario for such a community occurred on Cape Hatteras, North Carolina (Figure 1) during the summer of 2017. On July 27, a construction crew performing work on a new bridge inadvertently drove a steel casing through the single transmission line serving the community.[6] The resulting outage lasted for over a week during peak summer tourism season and the subsequent evacuation order cost residents an estimated $10 million in lost economic activity.[7] The outage was ultimately less impactful than initially forecast thanks in part to power supplied by two onsite diesel generators operated by Cape Hatteras Electric Cooperative (CHEC) with additional support from an influx of smaller generators. However, a greater portion of demand during the outage could have been met and the economic impact lessened had a microgrid with distributed generation been installed.

Figure 2. Map showing the location of Cape Hatteras on the coast of North Carolina.

The subtropical climate and geographic location of Cape Hatteras often puts the community directly in the path of seasonal tropical cyclones. The State Climate Office of North Carolina estimates eighty-three hurricanes made landfall in the state from 1851 to 2016, amounting to an average of one storm every two years.[8] Given the threat that hurricane winds and surge can pose to coastal barrier islands such as Hatteras, it becomes even more important for residents to have reliable access to power. The combined risk of natural disasters and human error prompts the need for an electricity generation and delivery system flexible enough to overcome these challenges. A microgrid deployment is the ideal all-in-one package for Cape Hatteras to accomplish this goal.

Before these technologies can be implemented, it is critical to first understand how they will impact residential customers. Alam, et al.[9] modeled energy cost optimization for smart homes connected to a smart grid. The study addressed cost-saving strategies for smart homes from the customer’s perspective and accounted for smart appliances and aggressive demand response schemes. Regarding microgrids, the study assessed cost minimization strategies associated with energy trading among participating households in a microgrid. However, the study was focused more on strategies to be utilized post-microgrid deployment and did not account for upfront capital costs, ongoing operational costs, and community-specific variables such as demand, generation mix, and initial retail rates.

A 2001 report by the Electric Power Research Institute (EPRI) concluded that "the use of uniformly distributed generation on microgrids facilitates the ability to build distribution systems that do not need any high-voltage elements—they are entirely low-voltage. This low-voltage approach demonstrates potential for significant cost savings, power quality/reliability improvements, and provide improved safety benefits as well."[10] Much like the Alam et al. report, the EPRI paper recommends strategies for cost savings and optimization, but does not attempt to quantify the rate increase resulting from a microgrid deployment.

There are examples in the literature of business models and financing schemes for microgrid systems although they fall short in addressing the impact on retail electricity rates specifically for residential customers. Hanna et al.[11] evaluates microgrid business models and addresses how policy impacts the cost of microgrid services. However, Hanna's analysis is limited to what they consider "typical commercial adopters: a large commercial building, critical infrastructure, and campus."[11] They then apply their model to a series of hypothetical commercial customers in Southern California. Of course, the load profile and microgrid characteristics will differ from a commercial customer in California compared to aggregated residential customers on Cape Hatteras, North Carolina.

There is clearly an opportunity for additional research given the lack of scientific literature assessing how retail electricity rates are impacted by a microgrid deployment. The following sections of this paper will seek to answer the following question: how would the deployment of a microgrid system with onsite generation affect retail electricity rates on Cape

Hatteras, NC? It is expected that rates will increase, although this is a tenuous expectation considering the substantial number of contributing variables and inputs.

The outcomes of this project will be two-fold. To properly address the question, a working model must first be developed that assesses the impact a microgrid and distributed resources (solar PV, diesel generation, battery storage, and demand response) would have on retail rates. This model will be intended for use by any community that wishes to better understand its grid reliability and resiliency options. The second outcome will be a proof-of-concept demonstration of the working model utilizing inputs specific to the community on Cape Hatteras.

2. Methods

The methods section is broken down into two subsections detailing first how the generic model was constructed in Microsoft Excel and next how the user-defined inputs were found for use in the model to assess how a microgrid deployment would affect retail rates on Cape Hatteras.

2.1 Model Development

While there is potential for a microgrid deployment on Cape Hatteras to significantly improve grid resiliency and reliability, it is critical to first assess the cost of these upgrades, how these costs would affect customers/residents, and how the avoided economic impact of outages compares to the costs of upgrading infrastructure. These key questions are central to the work of this project and answering them requires the use of a model. Thus, the first step is to develop a generic model that incorporates various demand and supply-side factors, financing parameters, capital costs, and operational cost data.

The model is built in Microsoft Excel with the following tabs: Summary, Microgrid, Solar, Diesel Generators, Battery Storage, Demand Response, Policy, and Avoided Costs. Where applicable, each tab accounts for the net change in retail rate and rate of return from deploying each individual technology while factoring in capital costs, O&M costs, fuel costs, generation capacity, utilization rates, and useful life. The Summary tab calculates the aggregated effect from each technology-specific tab.

Before diving further into how the model functions, it is first necessary to highlight the key general assumptions built into it. Other technology-specific assumptions will be discussed later.

- The model assumes costs are distributed equally across the rate base. While other cost-sharing schemes may result in a more proportionate distribution of costs amongst customers, for the purposes of simplicity, this model assumes equal distribution.
- All demand, price, and generation values were averaged over a month. Using more precise daily or even hourly values would provide more accurate modeling but again for purposes of simplicity, monthly average values are used.
- Construction times and inflation were not accounted for. Accounting for construction times would likely raise retail rates slightly,[12] and inflation would likely reduce rate of return[13], but neither was factored into this model.
- Capacity factors, utilization rates, and performance ratios were all assumed based on general estimates. Since this is a generic model, any future user would have better information as to the technology-specific inputs and could thus use more accurate data. However, the estimates used in this model are well-within the reasonable range of industry standards.

- It is assumed that all preexisting technologies are either fully paid off or that their costs are already factored into the initial retail rate.
- The model assumes that demand remains constant year-over-year. A more in-depth analysis would include demand projections into the future or utilize prior years data to more accurately understand how rates would project long-term.

Based on these assumptions, it is clear this model simplifies certain dynamic aspects of the cost assessments. However, this initial simplification offers the opportunity for further refining of the model in follow-up research.

With these assumptions in mind, the following will discuss how each tab functions by considering the user-defined inputs to calculate the change in retail rate for each month and overall rate of return for each project segment. Most tabs follow the same general format of distinguishing between upfront capital costs and recurring annual operations and maintenance (O&M) costs.

2.1.1 Summary

The Summary tab aggregates and summarizes the outputs from each technology-specific tab. Key user inputs are also located on the Summary tab including monthly demand (kW), average monthly wholesale electricity rate ($/kWh), monthly peak electricity rate ($/kWh), the initial retail rate ($/kWh), interest rate, basic service charge ($), the total number of service accounts, and the loan term in years.

The Summary tab also displays calculations for the monthly avoided demand (kW), monthly onsite generation (kW), monthly purchased generation (kW), and the overall change in retail rate and customer monthly bill ($/kWh and $/month, respectively). Additionally, the Summary tab shows the rate of return for the entire project by summing total capital costs and annual revenues, calculating the present value using the formula:

$$Vp (\$) = ((\text{Annual Revenue } (\$)/12) * (1 - ((1+\text{Interest Rate})^{(-12*\text{Loan Term (years)})}))/\text{Total Capital Costs}$$

and using the Excel rate of return function based on the present value and total capital costs.[14]

Rate of return for the entire project and for each individual segment is calculated by annualizing the monthly payments made by the rate base to cover the capital costs (monthly capital payments) and adding them to the annual onsite generation multiplied by the adjusted retail rate. The monthly capital payment is the amount of money paid by the rate base through increased retail rates. Because that increase would apply to all power generated onsite and purchased wholesale, the payments are treated as revenue from utility/co-op's perspective. Each project segment may also have additional revenue streams which will be detailed in the following pages. Utilizing the Excel rate of return function, the present value, and the total upfront capital costs yields the rate of return. It should be noted that an additional revenue stream from the demand response program at times when wholesale prices exceed retail rates. However, it is difficult to quantify these savings and therefore they were omitted when calculating annual revenue.

2.1.2 Microgrid

The Microgrid tab requires user inputs for design costs, capital costs, installation costs, additional overhead distribution line costs and footage, and additional underground distribution line costs and footage. There are also inputs for annual O&M costs, infrastructure replacement costs, and the microgrid useful life in years. As noted above, the costs are broken down by frequency: upfront and annually recurring.

The upfront costs are added together to produce the total upfront cost and the Excel payment function is used calculate the monthly payment based on the interest rate and loan term entered on the Summary tab.[15] The recurring annual costs are added together and divided by twelve to approximate the average monthly cost. Adding these two values together produces the total average monthly payment before factoring in the number of customer accounts.

Using this average monthly payment data and the user-entered initial price from the Summary tab, the microgrid's impact on electricity retail rate is calculated using the formula:

Adjusted Retail Rate ($/kWh) = ((Demand (kWh) * Initial Retail Rate ($/kWh)) + Monthly Payment ($)) / Total Accounts / Average Demand (kWh/account)

The result is the adjusted price, in $/kWh, for each month and the adjusted price is then subtracted from the initial price to calculate the net change in $/kWh.

2.1.3 Solar

The Solar tab calculates and displays the total costs from deploying utility-scale solar PV while also assesses the total potential onsite generation based on the solar irradiance at a given location. This tab requires user inputs for average irradiance for fixed and single axis tracking at a predetermined tilt angle (kWh/m^2/day), system capacity (kW), system cost ($/W), system useful life (years), performance ratio, capacity factor, and installation costs. There are separate inputs for each type of panel: fixed and single axis tracking. There is also a box for existing solar specifications should the user already have some amount of solar capacity. Monthly payments and rate of return are calculated using the same formula and methodology as the Microgrid tab.

A critical aspect of assessing the impact on retail rates from the deployment of solar PV capacity is to evaluate the amount of demand that can be met through onsite generation. These calculations are included on the Solar tab and begin by multiplying the average daily solar irradiance for both fixed and single axis tracking by the number of days in each month to get the average monthly irradiance. Then, the new monthly onsite generation for each type of system is calculated according to the formula:

New Monthly Generation (kWh) = Average Monthly Irradiance (kWh/m^2/month) * System Size (m^2) * Performance Ratio * Capacity Factor

The new monthly onsite generation is added to any existing onsite solar capacity to determine the total onsite generation in kWh. This value is then divided by the total number of accounts to determine the average demand per customer that is met with onsite generation.

Employing the calculated demand met through onsite generation (kWh/account) enables the total demand that must be purchased from offsite to be calculated by subtracting demand met onsite from total monthly demand. As in the Microgrid tab, the capital costs are summed and the Excel payment function is used to calculate the average monthly payment for upfront costs. The adjusted retail rate is then calculated according to the following formula:

Adjusted Retail Rate ($/kWh) = ((Average Purchased Demand (kWh/account) * Initial Retail Rate ($/kWh)) + Monthly Payment ($)) / Total Accounts / Average Demand (kWh/account)

Rate of return is calculated using the same formula as the Microgrid tab, but the methodology differs slightly. Annual revenue is made up in part from the monthly capital payment but there is also “revenue” added from the avoided purchase of power due to onsite generation. This is calculated by multiplying the average monthly onsite generation by the average monthly wholesale electricity rate. Summed up over the year and added to the monthly payments yields the total annual revenue from the solar project. The present value is calculated using the total solar capital costs and the same formula as explained under the Microgrid tab. Once the present value has been calculated, the Excel rate of return function is again used to determine the project rate of return.

2.1.4 Diesel Generators

The Diesel Generators tab displays cost and potential generation calculations for onsite peaker diesel generators. The following user inputs are required to evaluate the upfront capital costs: total generators, capacity (kW/generator), generator cost ($/kW), land costs, and installation costs. Using these inputs, the total upfront capital costs are calculated and as described for previous tabs, the Excel payment function is used to determine the total monthly payment for the entire rate base. The user then enters the expected annual O&M costs in $/kW/year. Multiplying the O&M cost by the capacity and dividing by twelve produces the monthly variable payment for the rate base.

To calculate the total onsite generation, the user must enter the additional following inputs: generator useful life (years), capacity factor, efficiency (kWh/gal), emissions rate (kgCO2/liter), and expected utilization rate (%). The total onsite generation is then calculated using the formula:

New Onsite Generation (kWh) = Capacity (kW) * (24*Days per Month) * Capacity Factor * Expected Utilization Rate

As with the Solar tab, there is a box on the Diesel Generators tab for existing capacity requiring user entry of the following data: existing capacity (kW), capacity factor, efficiency (kWh/gal), emissions rate (kgCO2/liter), and utilization rate (%). Adding the total existing and new onsite diesel generation enables the same calculation detailed under the Solar tab section to calculate the adjusted retail rate in $/kWh.

However, there are two additional factors influencing the adjusted retail rate from the diesel generators: fuel costs and carbon costs. To assess fuel costs, the sum of new and existing diesel generation (kWh) is divided by the generator efficiency (kWh/gal) to determine the monthly fuel usage. This fuel usage value is then multiplied by the average price per gallon of diesel fuel for that month to determine the total monthly fuel costs. To assess the monthly cost of carbon, if applicable, the emissions rate (kgCO2/liter) is converted to tons/gallon and multiplied by the monthly fuel usage to determine the monthly emissions in tCO2. Then based on the user-entered cost of carbon ($/ton) in the Policy tab of the model, the monthly cost of carbon can be determined.

Once fuel and carbon costs are calculated, the adjusted retail electricity rate is calculated according to the following formula:

Adjusted Retail Rate ($/kWh) = ((Average Purchased Demand (kWh/account) * Initial Retail Rate ($/kWh)) + Fuel Costs ($) + Carbon Costs ($) + Monthly Payment ($)) / Total Accounts / Average Demand (kWh/account)

Once the adjusted retail rate is calculated, it is subtracted from the initial retail rate to show the monthly impact of deploying the technology.

Rate of return for the Diesel Generator segment is calculated using the same formulas and methodology as previous tabs. Annual revenue is calculated by summing the annualized monthly fixed and variable payments and subtracting annual fuel and carbon costs. Additionally, as with solar, the avoided power purchased is included as revenue by multiplying monthly onsite generation and the peak electricity rate, given the new diesel generators are expected to serve as peakers. The present value is calculated using the same formula detailed above and the Excel rate of return function is used.

2.1.5 Battery Storage

The Battery Storage tab displays cost and potential avoided demand calculations for onsite lithium-ion battery storage. For the purposes of this model, it is assumed the batteries are utilized during times of peak demand. The user must first enter the battery cost ($/kWh), land and installation costs, the total number of batteries deployed, the system useful life (years), the system efficiency (%), and the capacity (kWh/battery). The total upfront capital cost is then calculated by multiplying the battery cost in $/kWh by the total capacity and adding in land and installation costs. Using the Excel payment function then generates the total monthly payment to be spread across the rate base. The user then must input the expected O&M costs in $/kWh and the variable cost is calculated by multiplying the O&M cost by the system capacity and dividing by twelve.

As in other tabs, there is a box on the Battery Storage tab for existing system specifications to account for any existing storage capacity. The user must enter the size of the system (kW), the capacity (kWh), the efficiency (%), and useful life (years).

The next step is to calculate the average new avoided demand for each month. This is accomplished using the formula:

New Avoided Demand (kWh) = Total Units * Capacity (kWh) * Efficiency (%) * Days per Month

Adding the new avoided demand with any demand avoided due to existing technologies deployed yields the total average monthly avoided demand. Dividing this total by the number of accounts then gives the average demand avoided per account and subtracting this value from the total average demand for the month yields the average demand supplied through offsite generation purchases. The adjusted retail rate is then calculated the same way as other tabs using the formula:

Adjusted Retail Rate ($/kWh) = ((Offsite Demand (kWh) * Initial Retail Rate ($/kWh)) + Monthly Payment ($)) / Total Accounts / Average Demand (kWh/account)

Rate of return for the battery storage portion of the project is calculated by annualizing the monthly payments made by the rate base to cover the capital costs. This revenue is added to the sum of average monthly avoided demand multiplied by the peak electricity rate to determine the total annual revenue. The present value is then calculated using the formula discussed under the Summary tab. Then utilizing the Excel rate of return function, the present value and the total upfront capital costs yield the rate of return for the battery segment.

2.1.6 Demand Response

The Demand Response tab evaluates the impact on retail electricity rates if a demand response scheme was put in place. The demand control method in this scenario is the installation of programmable Ecobee thermostats that allow for a utility or cooperative to control the temperature in participating homes three degrees Fahrenheit above or below the homeowner's preferred setting. It is expected that load would be shed during peak times, further increasing the value to the operator while returning a monthly payout to the enrolled customers.

The user inputs for the Demand Response tab include the total number of new thermostats, the cost per thermostat, the installation cost per thermostat, expected annual O&M costs, the expected annual cost of replacement parts, the average demand avoided (kWh/day/thermostat), the monthly payout to enrolled customers, and the useful life in years of the thermostats. As with the other tabs, there is a box for new system specifications in addition to existing system specifications, if applicable.

The total upfront capital costs are calculated by adding the total cost of all the new thermostats and the total cost of installation. The Excel payment function is used to determine the monthly payment for the entire rate base according to the expected useful life of the thermostats. Annual O&M and replacement parts costs are added together and divided by twelve to find the monthly variable cost payment for the rate base.

The methodology is the same for calculating both the new and existing potential avoided demand in kWh and utilizes the following formula:

Avoided Demand (kWh) = Total New Thermostats * Average Demand Avoided (kWh/day/thermostat) * Days per Month

Adding the new and current demand avoided each month produces the total demand avoided which is then subtracted from the total monthly demand to yield the total amount of electricity purchased from offsite generation. The adjusted retail rate is calculated according to the formula:

Adjusted Retail Rate ($/kWh) = ((Average Purchased Demand (kWh/account) * Initial Retail Rate ($/kWh)) + Monthly Payment ($)) / Total Accounts / Average Demand (kWh/account)

and the net change is calculated by subtracting the initial from the adjusted rate.

Rate of return is calculated using the same formula and Excel function however for the Demand Response tab, there are slightly different elements that make up the annual revenue. Revenue sources include the monthly capital and O&M payments as well as the avoided demand (kWh) multiplied by the peak rate ($/kWh). However, there is an additional revenue stream from the sale of the thermostats (total new thermostats * thermostat cost). There is also the additional expense of paying the enrolled customer payout for utilizing the demand response program (-total new thermostats * customer payout). Total annual revenue is then converted to present value based on the formula detailed previously and the Excel rate of return function is used to evaluate rate of return based on the capital expenditures and the present value of the annual revenue.

2.1.7 Policy

The Policy tab contains optional user inputs that account for tax credits or grants that may have assisted in financing any of the five project segments: microgrid, solar, diesel generators, battery storage, and/or demand response. The model treats these inputs as a reduction in the capital cost of a segment of the microgrid system, thereby reducing the cost to the rate base and improving rate of return. The Policy tab also contains the user input for a carbon price which, as discussed in the Diesel Generators tab, would increase costs across the rate base.

It should be noted that all the inputs on the Policy tab are optional and the model runs effectively without them being entered. However, on-the-ground situations can vary greatly between users, so it was important to try to account for as many variations as possible.

2.1.8 Avoided Costs

The Avoided Costs tab accounts for the potential economic impact of a major outage and the frequency of such an outage. The model treats this impact as additional annual revenue for the system by dividing the outage frequency by the loan term, then multiplying this value by the cost of the outage. This value is then multiplied by the sum of the percent of demand met with onsite generation and the percent of demand avoided. It is then added in as additional revenue and the rate of return is recalculated based on the methodology described in previous sections. As with the Policy tab, the Avoided Costs tab is an optional user input.

2.2 Model Application

Once the functional generic model was developed using placeholder values for the user inputs, research into real data points was performed to better understand how a microgrid deployment would affect retail rates for customers on Cape Hatteras. The following sections will discuss in depth the sources of the manual inputs used to answer this question.

All the same assumptions discussed in the context of the generic model were relevant, however some assumptions were made specific to the Cape Hatteras application of the model and should be addressed before further discussion.

- CHEC retail rates vary based on whether the customer is residential or commercial. For modeling purposes, the lower residential rates were used as inputs for two reasons: A lower initial rate would lead to a more conservative estimate of change in retail rate and the demand data did not distinguish between commercial and residential demand. Additionally, demand inputs include demand from both residential and commercial customers. Although this should have a minimal effect on the rate in $/kWh, it will likely result in an overestimate of the total monthly bill for residential customers and an underestimate of the total monthly bill for commercial customers.
- CHEC also varies its rates based on the season. For the purposes of this model, the winter season will run from November to April and the summer season will run from May to October.

2.2.1 Summary

The inputs on the Summary tab are the most crucial in terms of determining how a microgrid deployment on Cape Hatteras would affect retail electricity prices. The first key piece of information is peak monthly demand. George Price, Manager of Engineering and Operations at CHEC, provided this 2016 data via email on October 27, 2017. This data is shown in Figure 3 and suggests significant seasonal variability.[16] This is due in part to the nature of the Cape Hatteras economy and its reliance on an influx of tourists during the summer season.

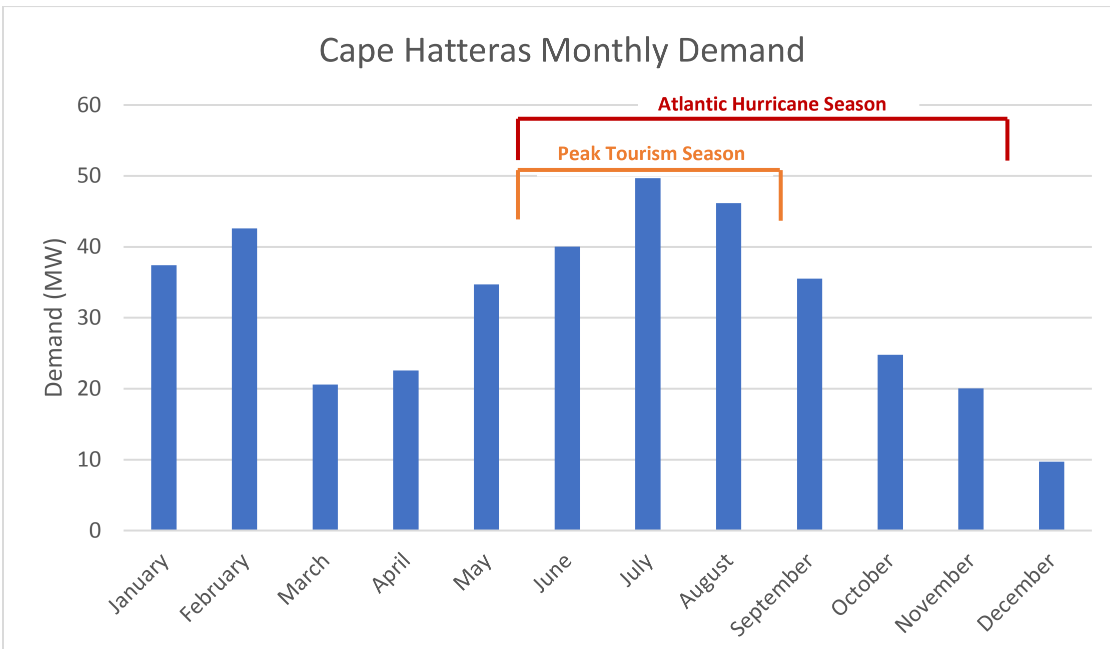

Figure 3. Monthly peak electricity demand in MW for Cape Hatteras, NC.

Cape Hatteras in located within the Pennsylvania-New Jersey-Maryland (PJM) Interconnect and therefore, data from the PJM website was used to determine the average wholesale and peak rates.[17] The methodology used to calculate average monthly wholesale price is as follows. The PJM hourly real-time locational marginal price (LMP) data was downloaded from the website. This dataset presents the hourly price per kilowatt-hour over the course of a month. A simple mean average was then taken to determine the average monthly wholesale price. The monthly data was used between November 2016 and October 2017, which was the last full month of data available. The same methodology and LMP dataset was used to determine the monthly peak price but instead of taking the average of the hourly price, the maximum was used.

As noted in the assumptions, CHEC employs seasonal pricing rates on Cape Hatteras. The following are the initial retail rates for residential customers. For the first 1,000 kWh during the summer months, the rate is $0.1008/kWh and every kWh after 1,000 costs $0.1460.[18] During the winter season, the first 1,000 kWh cost the same $0.1008/kWh but every kWh after 1,000 costs $0.0956.[18] The monthly initial retail rate was then calculated using the formula:

Initial Retail Rate ($/kWh) = ((1000*First 1k rate) + ((Monthly demand – 1000) * Over 1k rate)) / Average Demand (kWh/account)

There is also a basic monthly service charge of $20.00 per account.[18]

The interest rate of 4.2% and the total number of accounts, 7,600, were also provided my Mr. Price.[19,20] Typically, electricity cooperatives borrow money from the Rural Utilities Service, an operating unit of the United States Department of Agriculture.[21] While the interest rate varies, Mr. Price indicated it typically averages around 4.2%. Lastly, the loan term of 25 years was estimated based on the reasonable range of industry standards.

2.2.2 Microgrid

Microgrids are highly customizable systems and are designed to meet the specific needs of a community. To produce highly accurate inputs for the Microgrid tab, a separate study would need to be conducted to determine capital and O&M costs. Without the benefit of such a study specific to Cape Hatteras, alternatives had to be considered.

In 2014, the New York State Energy Research and Development Authority (NYSERDA) announced a statewide request for microgrid feasibility studies.[22] The goal of the competition, known as NY Prize, was to select winning projects for funding that would help communities deploy microgrids to improve disaster planning and transition away from fossil fuels.[22] Eighty-three feasibility studies were selected as stage 1 winners. These studies were posted to the NYSERDA website and are available for public viewing.

The microgrid feasibility study performed for the Town of Moreau in Upstate New York by Booz Allen Hamilton Inc. was selected as one of the stage 1 winners. The June 2016 feasibility study offers a valuable source of information for understanding various microgrid costs. Moreau is about twice the population of Hatteras but still serves as a useful proxy for assessing the costs of a microgrid deployment. Thus, the following inputs were taken from Moreau's microgrid feasibility study: microgrid design costs ($150,000), capital costs ($655,000), installation costs ($80,000), annual O&M costs ($70,000), the annual cost infrastructure replacement ($25,000), and the microgrid useful life (25 years).[23] The remaining inputs for overhead and underground distribution line costs ($3.70/ft and $9.00/ft, respectively) were taken from the CHEC website, but it was assumed that no additional lines would need to be installed at this time.[18] The capital costs for the microgrid components would come from breakers to assist with entering and exiting islanded mode, control systems, frequency regulating equipment, and additional software. There will likely be additional costs associated with training current CHEC employees as well.

2.2.3 Solar

One of the most critical values for understanding the solar capacity at a location is the incoming solar irradiance. The United States National Renewable Energy Laboratory (NREL) maintains a publication of solar irradiance values for specific locations, including Cape Hatteras.[24] For the purposes of the model, both the fixed and single axis tracking solar panels were assumed to be tilted at degrees latitude and the average monthly irradiance was used.

The fixed and single axis capacity (750 kW and 500 kW, respectively), performance ratios (72% and 75%, respectively), capacity factors (25% and 23%, respectively), useful life (20 years), and installation costs ($50,000) were all estimated based on the reasonable range of industry standards.

The cost of the solar cells ($1.03/W for fixed and $1.11/W for single axis tracking) was taken from the NREL US Solar Photovoltaic System Cost Benchmark for 1Q2017 and includes the cost of land and expected lifetime O&M.[25]

Lastly, Cape Hatteras has a small 50kW community solar garden onsite. The specifications for this technology were taken from the CHEC website.[26] The panels were assumed to be single axis tracking and performance ratio (77%) and capacity factor (25%) were estimated based on the reasonable range of industry standards.

2.2.4 Diesel Generators

The inputs for the Diesel Generators tab begin with the cost of diesel fuel in dollars per gallon. This data was obtained from the EIA website[27] and as noted before, does not account for the cost of transportation and distribution. The prices used represent the average monthly retail price of U.S. No 2 ultra-low sulfur (0-15 ppm) diesel and span from November 2016 to October 2017.

The land costs ($250,000), installation costs ($75,000), capacity (1,000kW/generator), number of generators (3), useful life (20 years), system capacity factor (52%), and expected utilization rate (5.0%), were all estimated based either on the reasonable range of industry standards or on the most reasonable expectation for peaker diesel generator usage.

The Lazard Levelized Cost of Energy (LCOE) v10.0 was used to determine the generator cost ($/kW) and annual O&M costs ($/kW).[28] Under the "Capital Cost Comparison" chart, for diesel reciprocating engines, the LCOE is estimated in the range of $500/kW to $800kW.[28] Thus, for the purposes of the model, the cost was assumed to be $650/kW. The value for the annual O&M costs was taken from the "Key Assumptions" chart which suggests $15.00/kW-year for the diesel reciprocating engine.

It is also to know the generator efficiency, in kWh/gal, to calculate the total fuel costs. Ann Chambers, Associate Editor of *Power Engineering*, oversaw the three-month trial of a series of fluid dynamic power cells to test and quantity efficiency increases by generators at Flinders Island Power Station in Australia. Total capacity of the two Caterpillar 3512 diesel generators and two Rolls Royce C6200G diesel generators tested was 1,550 kW, similar to the assumed capacity for the Cape Hatteras generators.[29] Before installation of the efficiency upgrades, the system had run for 7,000 hours with an average efficiency of 16.5 kWh/gal.[29] Since there is no expectation the Cape Hatteras generators will not be fitted with efficiency upgrades, this 16.5 kWh/gal was used as the diesel generator system efficiency input for the model.

Determining the monthly cost for carbon depends almost entirely on the emissions rate from the diesel generators. According to Jakhrani, et al., "the number of kg of CO_2 produced per liter of fuel consumed by the diesel generator depends upon the characteristics of the diesel generator and of the characteristics of the fuel, and it usually falls in the range of 2.4−2.8kg/l."[30] Thus, the model assumes the average emissions rate for the diesel generators to be 2.6kgCO_2/liter of diesel fuel.

As noted previously, there are two existing diesel generators available to CHEC. The capacity is owned by the North Carolina Electric Membership Corporation (NCEMC) which represents electric cooperatives throughout the state.[20] NCEMC bids the Cape Hatteras generators into PJM during peak times. George Price from CHEC provided the specifications used in the model for the existing generators including a capacity of 15 MW and utilization rate of ~1%.[31] The remaining parameters were estimated based on the reasonable range of industry standards.

2.2.5 Battery Storage

The costs for lithium-ion battery storage technologies is one of the most rapidly changing in the industry. It can therefore be assumed that by the time this model is being used, the costs for battery storage will have fallen significantly. However, this model provides a snapshot in time in this instance and therefore utilizes the best available data.

The capital and O&M cost inputs for the Battery Storage tab were taken from the Lazard Levelized Cost of Energy Storage (LCOS) v2.0.[32] The lithium-ion battery system in the model is assumed to intended for use in offsetting peak demand and therefore, the LCOS costs for a peaker replacement lithium-ion battery were used. To determine the O&M costs using the LCOS, a median average was taken using the low and high end levelized cost of storage components yielding an estimate of $0.0295/kWh annually.[32] To produce the capital cost estimate for the battery storage component, the "Capital Cost Comparison" table in the LCOS was used. The values for peaker replacement lithium-ion batteries are listed in a high to low range and therefore, the median average was again taken to produce an estimate of $683/kWh in capital costs. The Lazard LCOS was also used to produce inputs for the average system efficiency (90%) and the projected useful life (10 years).[32]

The land costs ($100,000), installation costs ($50,000), size (500 kW/battery), capacity (1,500 kWh/battery), number of batteries (2) were all estimated based on the reasonable range of industry standards.

CHEC does not currently employ and battery storage and therefore the box for existing system specifications was not utilized when modeling how a microgrid deployment would affect retail rates on Cape Hatteras.

2.2.6 Demand Response

The inputs for the Demand Response tab are straightforward and begin with the Ecobee thermostat installation costs of $25 per unit, the total new thermostats (250), annual O&M costs of $1,000, and an estimated annual cost of $250 for replacement parts. These values were estimated based on the reasonable range of industry standards or as in the case of the total new thermostats, estimated to provide a realistic target for new installations. The useful life of 40 years for the thermostats was taken from the Ecobee website.[33]

CHEC currently has a demand response program that has been operating for about two years.[19] Per Mr. Price, "We sell them to members at a discounted rate of $50 for the Ecobee 3 and $25 for the Ecobee 3 Lite. If the member has all electric heating and cooling, and agrees to allow the cooperative to control their thermostat at times of peak, they are given a $4 per month credit per account regardless of the number of units in a single home…We currently have 181 thermostats participating in the program… We typically have events during the peak summer months of June, July, and August, and winter months of January and February. Because of our rate structure for purchased power there is no benefit to calling on the thermostat during the shoulder months."[19] The "Existing System Specifications" box was populated using these inputs and the assumption of a fifty-fifty split between Ecobee 3 and Ecobee 3 Lite thermostats ($37.50 per unit). Mr. Price also provided data indicating the average demand avoided per thermostat is roughly 0.25 kwh/day.[19]

2.2.7 Policy

There were no inputs utilized under the Policy tab for any tax incentives or grant money provided to help fund the project. Additionally, the price of carbon was set to zero as well. Although these inputs were not used to model how a microgrid deployment would affect Cape Hatteras retail rates, they offer the opportunity to "play" with the model and assess the impact different factors can have.

2.2.8 Avoided Costs

The $10,000,000 estimated economic impact of a major outage input in the Avoided Costs tab comes from an estimate performed from the summer 2017 outage.[7] The frequency of such an outage comes from estimates performed by Vecci, et al. who state, “retrospective predictions of 5- and 9-yr mean tropical Atlantic hurricane frequency show significant correlations relative to a null hypothesis of zero correlation.”[34] As seen in July 2017, outages can be caused by events other than hurricanes, however given Cape Hatteras’s location, a hurricane is the most likely source of such a catastrophic outage. Accordingly, a 7-year average is used for the model.

It is essential to note that although the inputs in the Avoided Cost tab are optional, the entire purpose of deploying a microgrid is to improve grid resiliency and response to extreme events/outages. Avoided cost data is therefore critical in evaluating the economics of a microgrid system.

3. Results

Using the above methodology and sources of Cape Hatteras-specific inputs, the model was run to produce the net change in retail electricity rate and the corresponding difference in average monthly electricity bill incurred by the entire project. Table 1 shows the table produced by the Summary tab and in addition to the rate/bill changes, shows a breakdown of the total avoided demand, total onsite generation, and total purchased generation. Values in red text indicate user-entered inputs while cells in black indicate calculated values. A more in-depth breakdown of the impact of each individual segment can be found in the Appendix.

Summary	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
Peak Demand (kW)	37,430	42,610	20,570	22,550	34,710	40,020	49,700	46,170	35,500	24,790	20,030	9,710
Peak Demand (kWh)	27,847,920	28,633,920	15,304,080	16,236,000	25,824,240	28,814,400	36,976,800	34,350,480	25,560,000	18,443,760	14,421,600	7,224,240
Avg Demand (kWh/account)	3,664	3,768	2,014	2,136	3,398	3,791	4,865	4,520	3,363	2,427	1,898	951
Avoided Demand (kW)	117	117	113	113	113	117	117	117	113	113	113	113
Avg Avoided Demand (kWh/account)	11.5	10.3	11.0	10.7	11.0	11.1	11.5	11.5	10.7	11.0	10.7	11.0
% of Demand Avoided	0.3%	0.3%	0.5%	0.5%	0.3%	0.3%	0.2%	0.3%	0.3%	0.5%	0.6%	1.2%
Onsite Generation (kW)	538	610	692	771	762	756	749	736	707	654	579	520
Avg Onsite Generation (kWh/account)	53	54	68	73	75	72	73	72	67	64	55	51
% of Demand met with Onsite Generation	1.4%	1.4%	3.4%	3.4%	2.2%	1.9%	1.5%	1.6%	2.0%	2.6%	2.9%	5.4%
Purchased Generation (kW)	36,775	41,883	19,765	21,666	33,836	39,147	48,834	45,317	34,680	24,024	19,339	9,078
Purchased Generation (kWh/account)	3,600	3,703	1,935	2,053	3,312	3,709	4,781	4,436	3,286	2,352	1,832	889
% of Generation Purchased	98.2%	98.3%	96.1%	96.1%	97.5%	97.8%	98.3%	98.2%	97.7%	96.9%	96.5%	93.5%
Avg Wholesale Rate ($/kWh)	0.0310	0.0252	0.0314	0.0277	0.0297	0.0266	0.0307	0.0262	0.0297	0.0276	0.0252	0.0313
Peak Rate ($/kWh)	0.1520	0.0795	0.1575	0.1018	0.1612	0.1055	0.1573	0.1075	0.6546	0.1432	0.1173	0.2271
Initial Retail Rate ($/kWh)	$0.0970	$0.0970	$0.0982	$0.0980	$0.1327	$0.1341	$0.1367	$0.1360	$0.1326	$0.1274	$0.0983	$0.1008
Adjusted Retail Rate ($/kWh)	$0.0976	$0.0975	$0.0984	$0.0980	$0.1318	$0.1333	$0.1360	$0.1353	$0.1319	$0.1268	$0.0993	$0.1029
Difference ($/kWh)	**$0.0005**	**$0.0005**	**$0.0002**	**($0.0000)**	**($0.0009)**	**($0.0008)**	**($0.0007)**	**($0.0007)**	**($0.0006)**	**($0.0006)**	**$0.0009**	**$0.0021**
Initial Bill ($/account)	$375.50	$385.38	$217.71	$229.43	$470.90	$528.34	$685.14	$634.69	$465.82	$329.11	$206.61	$115.82
Adjusted Bill ($/account)	$371.22	$381.08	$210.42	$221.22	$456.46	$514.42	$670.22	$620.23	$453.49	$318.25	$201.87	$111.42
Difference ($/account)	**($4.27)**	**($4.30)**	**($7.28)**	**($8.21)**	**($14.44)**	**($13.92)**	**($14.92)**	**($14.46)**	**($12.33)**	**($10.86)**	**($4.74)**	**($4.40)**

Table 1. Table showing how a microgrid deployment would affect retail electricity rates on Cape Hatteras, NC.

The model suggests a net increase in the $/kWh retail rate for the months of January, February, March, November, and December and a net decrease for the months of April through October due to the higher initial retail rate. The modeling also suggests an average monthly bill reduction of $9.51 per account leading to a decrease of $114.14 per year. These impacts are summarized in Figure 4.

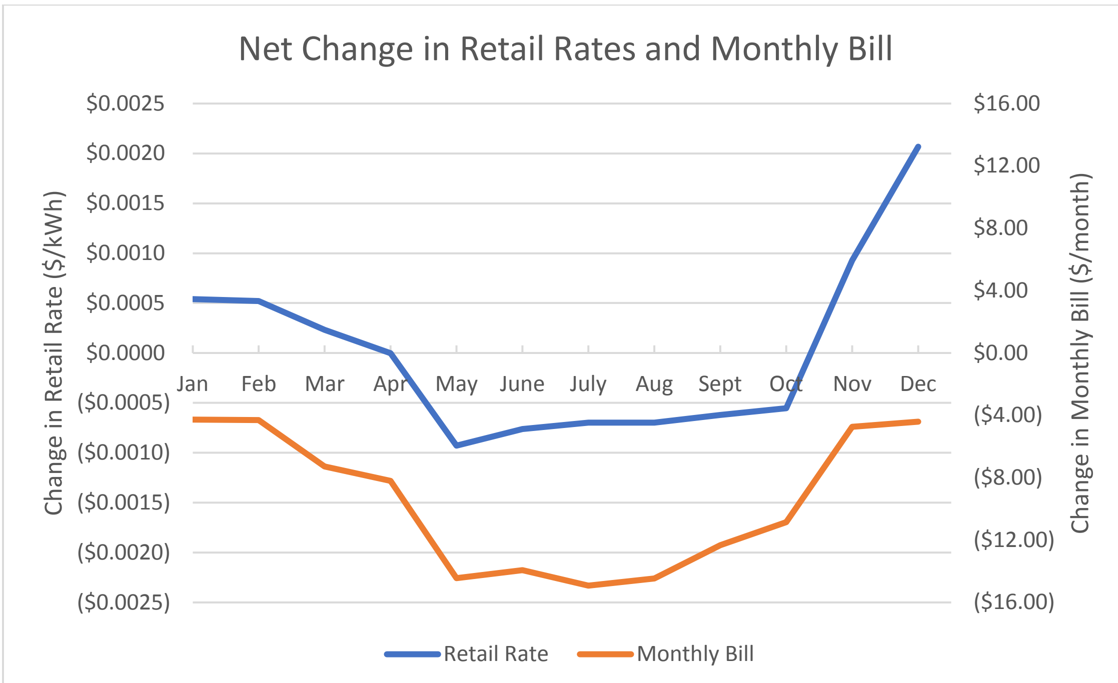

Figure 4. Chart showing the monthly impact on retail rates and average customer bill.

One key takeaway from Figure 4 is that even in the months where the retail rate increases (November through March), the average monthly bill still decreases. This occurs because of the increased onsite generation resulting in less electricity being purchased from the macrogrid. Although the cost per kWh increases due to the cost of deploying the microgrid, the total kWh purchased decreases due to the onsite generation leading to a monthly savings for customers.

The overall rate of return on the project is -21%, well below the 4.2% interest rate. The user inputs and rate of return breakdown are displayed in Table 2. Such a negative rate of return for CHEC suggests additional rate increases would be necessary for the project to become economically viable. An increase in retail rates could improve the economics to make a microgrid deployment more appealing, however it is likely the community would be averse to such an action. It is also important to note that most microgrids deployed currently utilized some amount of grant money. While the Cape Hatteras microgrid modeled in this paper did not include any hypothetical grant money, doing so significantly improves the rate of return.

First 1,000 kWh Summer Rate ($/kWh)	$0.1008
Over 1,000 kWh Summer Rate ($/kWh)	$0.1460
First 1,000 kWh Winter Rate ($/kWh)	$0.1008
Over 1,000 kWh Winter Rate ($/kWh)	$0.0956
Interest Rate	4.20%
Basic Service Charge	$20.00
Total Accounts	7,600
Loan Term (yrs)	25

Annual Rev	$2,684,368
Capital	($6,758,375)
Vp	$5,326,103
RoR	**-21%**

Table 2. Tables showing key user inputs and the overall rate of return for the project.

Figure 5 shows the correlation between initial retail rates and the change in rates resulting from the microgrid deployment. The data suggest that when initial retail rates are higher, there is a decrease in the $/kWh cost after deployment of the microgrid and when initial retail rates are lower, the rate either remains the same or increases. This trend supports the economic case for microgrids in rural and remote communities where residents typically pay a premium for electricity.

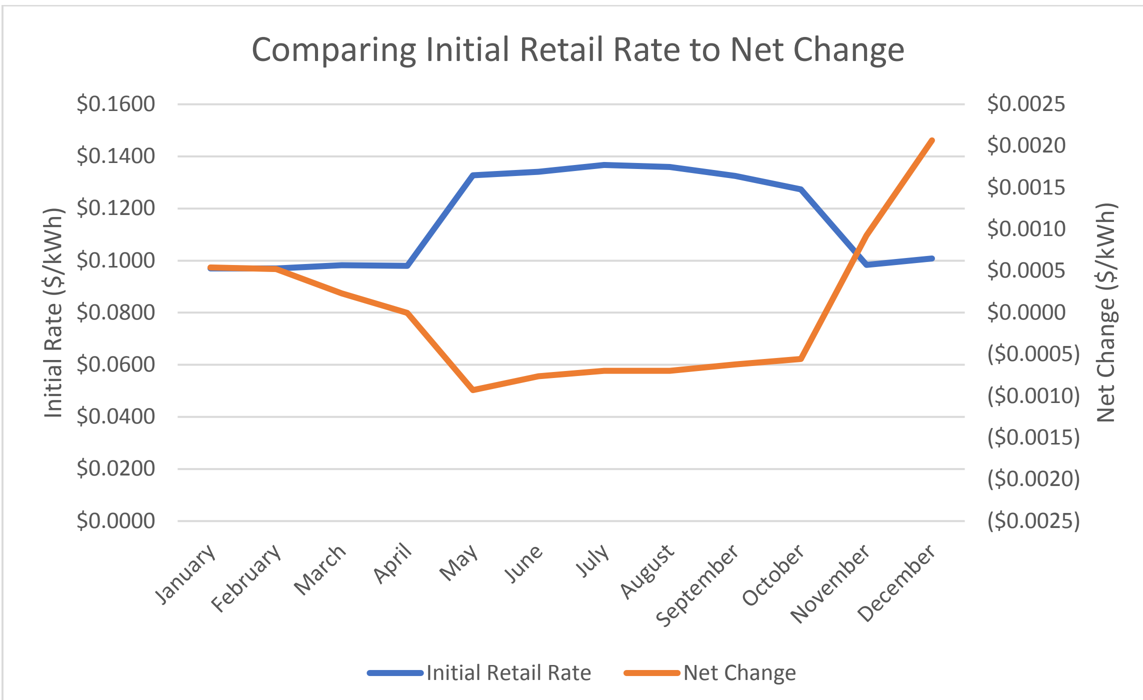

Figure 5. Figure comparing the initial monthly retail rate and net change resulting from the microgrid deployment.

The average monthly bill decrease throughout the year is due in part to the reduction in electricity purchased by CHEC from the macrogrid. This “avoided purchased demand” is broken down into two sources: demand met via onsite generation and demand avoided. Demand met via onsite generation is reflective of the electricity generated from the solar, diesel generator, and battery storage components. The avoided demand is the result of the demand response program. Figure 6 shows the breakdown of each source of avoided purchased demand. An annual average of 2.5% of initial demand can be met with the increased onsite generation while an additional annual average of 0.4% can be avoided through demand response.

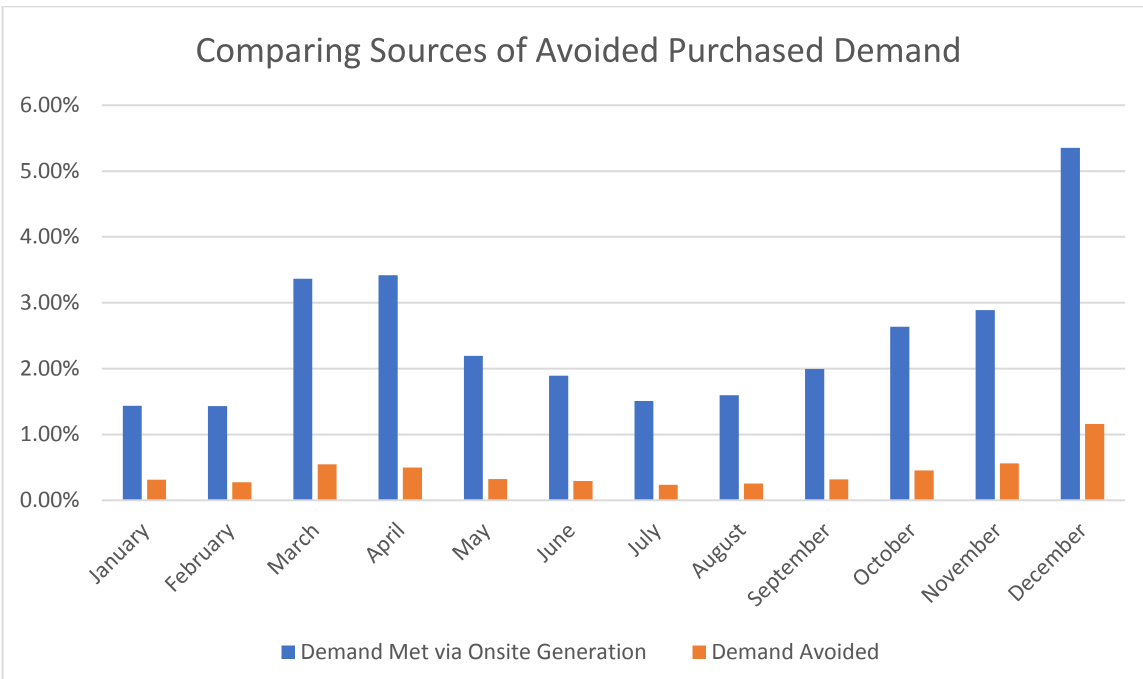

Figure 6. Comparing the percent of initial demand met through onsite generation and the percent avoided.

Figure 7 shows the average monthly onsite generation after the microgrid is deployed. This trend correlates with the average monthly solar irradiance. Traditional, fossil-fuel based forms of electricity generation are not seasonally dependent and can be run as frequently or infrequently as the operator decides. Assuming the same monthly output from the diesel generators results in the monthly variations being solely due to varying solar irradiance. With higher irradiance in Cape Hatteras during the late spring and early summer months, generation in kWh/account is higher than in the winter where average incoming solar radiation is lower.

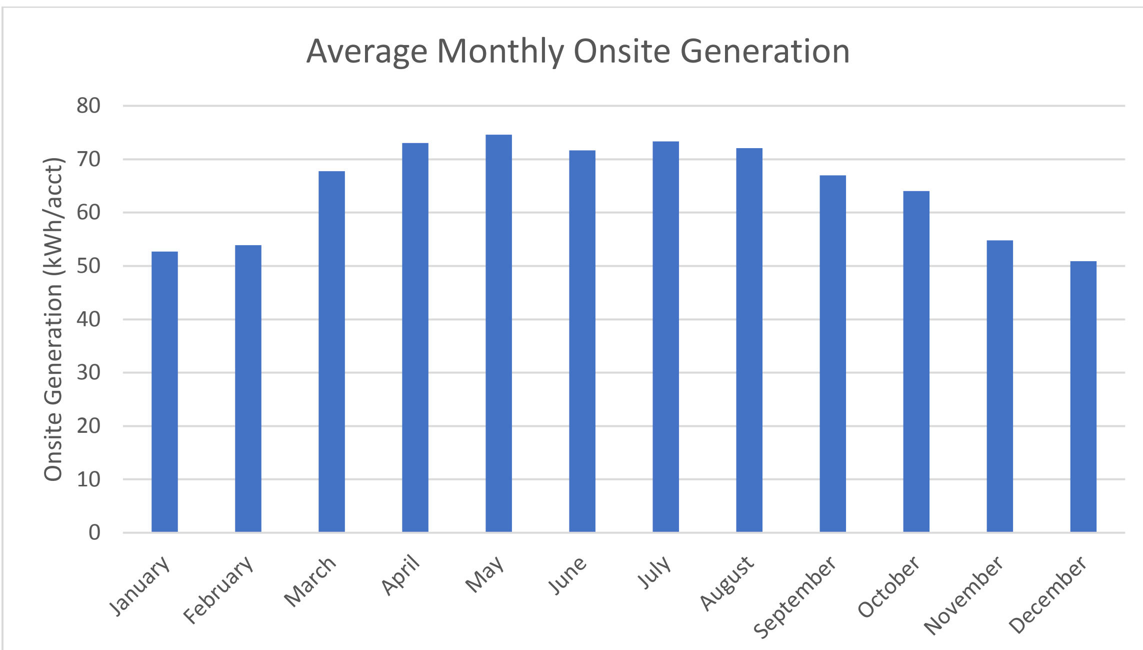

Figure 7. The average monthly onsite generation available after the microgrid deployment.

4. Discussion

This project began by asking the initial question: how would the deployment of a microgrid system with onsite generation affect retail electricity rates in general and how would rates on Cape Hatteras, NC be impacted following the outage of summer 2017? It was initially expected that retail rates would rise throughout the year. However, after producing the generic model and processing roughly seventy-five Hatteras-specific inputs, it has become evident that the hypothesis was incorrect. Retail electricity rates would increase slightly from November to March but decrease slightly from April to October resulting in overall annual savings.

The change tends to correlate with the initial average retail rate for each month. In months when the initial rate is higher, adjusted retail rates are reduced and in months when the initial rate is lower, retail rates increase from the microgrid deployment. This trend further supports the economic case for microgrids in rural and remote communities that typically pay a premium for electricity.

A microgrid deployment on Cape Hatteras could offer significant benefit to both the customers and CHEC. Absent the costs, the improved resiliency would be critical in responding to hurricanes and would help mitigate the economic impact of outages. Additionally, the resiliency improvement could serve as an incentive to attract business to the area by ensuring a near-constant availability of electricity.

There would be some negative aspects to a microgrid deployment as well. The initial capital costs are significant and could in fact be higher than the inputs used in the model. Further, the active load management capabilities by the microgrid are complex and would likely require either training for current CHEC employees or the hiring of additional employees, both of which were not accounted for in the model.

While the model provides a snapshot in time of current (fall 2017) generation prices, it can be reasonably expected the costs, particularly for solar and lithium-ion batteries, will continue to decrease. Accordingly, it is informative to run the model using reduced costs for these technologies to assess how costs can be projected to change and determine if waiting some amount of time for a microgrid deployment to make more economic sense. Assuming a ten percent reduction year-over-year for solar and battery costs suggests that in the year 2020, fixed solar, single-axis tracking solar, and battery costs would be $0.75/W, $0.81/W, and $498/kWh, respectively. Holding all other variables constant, residents would save an additional $12.12 per year on electricity costs on Cape Hatteras.

Projecting these cost reductions out to 2030 suggests fixed solar, single-axis tracking solar, and battery costs would be further reduced to $0.26/W, $0.28/W, and $174/kWh, respectively. This reduction, holding all other variables constant, would result in an annual additional savings of $33.67 for CHEC customers compared to 2017, with the majority of savings attributable to battery storage cost reductions.

As noted throughout this paper, the model developed is simplified and accounts for only the major cost impacts. Thus, there is opportunity for further, more in-depth follow-up research. One such area would be to utilize policy inputs to assess the impact on retail fates from certain policies such as investment tax credits, grant money, and a carbon tax. Another opportunity would be to perform a sensitivity analysis to assess which inputs have the most significant on retail rates. Another opportunity for further research would be to incorporate wind generation into the modeling. Cape Hatteras has notable wind resources, especially offshore, and aside from other community concerns, it would be interesting to understand how deploying wind capacity would affect CHEC retail rates. An additional area for further research is to look at what change in retail rates would be necessary to improve the rate of return such that a microgrid deployment would make economic sense for CHEC. This paper and model were designed to evaluate a microgrid from the customers’ perspective. However, it would be equally as informative to understand the model from CHEC’s perspective.

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6. Appendix

The following set of tables show a breakdown of how the microgrid technology, solar, diesel generators, battery storage, and demand response segments each factored in to the overall cost impacts. Values in red text indicate user-entered inputs while cells in black indicate calculated values.

Microgrid

Microgrid	January	February	March	April	May	June	July	August	September	October	November	December
Peak Demand (kW)	37,430	42,610	20,570	22,550	34,710	40,020	49,700	46,170	35,500	24,790	20,030	9,710
Peak Demand (kWh)	27,847,920	28,633,920	15,304,080	16,236,000	25,824,240	28,814,400	36,976,800	34,350,480	25,560,000	18,443,760	14,421,600	7,224,240
Avg Demand (kWh/account)	3,664	3,768	2,014	2,136	3,398	3,791	4,865	4,520	3,363	2,427	1,898	951
Initial Retail Rate ($/kWh)	$0.0970	$0.0970	$0.0982	$0.0980	$0.1327	$0.1341	$0.1367	$0.1360	$0.1326	$0.1274	$0.0983	$0.1008
Adjusted Retail Rate ($/kWh)	$0.0975	$0.0974	$0.0990	$0.0988	$0.1332	$0.1345	$0.1371	$0.1364	$0.1331	$0.1281	$0.0992	$0.1026
Difference ($/kWh)	**$0.0005**	**$0.0004**	**$0.0008**	**$0.0008**	**$0.0005**	**$0.0004**	**$0.0003**	**$0.0004**	**$0.0005**	**$0.0007**	**$0.0009**	**$0.0018**

Table A1. Table showing the impact on retail electricity rates from the microgrid segment.

Microgrid Specifications	Cost ($/ft)	Feet	Cost	Frequency		
Design Costs			$150,000			
Capital Costs			$655,000			
Additional Overhead Distribution Line	$3.70	0	$0			
Additional Underground Distribution Line	$9.00	0	$0			
Installation Costs			$80,000			
			$885,000	Upfront	**$4,770**	**Per Month**
O&M			$70,000			
Infrastructure Replacement			$25,000			
			$95,000	Per Year	**$7,917**	**Per Month**

Annual Rev	$152,236
Capital	($885,000)
Vp	$302,054
RoR	**-66%**

Useful Life (yrs)	25

Table A2. Tables showing specifications, cost inputs, and rate of return for the microgrid segment.

Solar

	Solar	January	February	March	April	May	June	July	August	September	October	November	December
	Peak Demand (kW)	37,430	42,610	20,570	22,550	34,710	40,020	49,700	46,170	35,500	24,790	20,030	9,710
	Peak Demand (kWh)	27,847,920	28,633,920	15,304,080	16,236,000	25,824,240	28,814,400	36,976,800	34,350,480	25,560,000	18,443,760	14,421,600	7,224,240
	Avg Demand (kWh/account)	3,664	3,768	2,014	2,136	3,398	3,791	4,865	4,520	3,363	2,427	1,898	951
	Avg Onsite Demand (kWh/account)	38	40	53	59	60	57	58	57	52	49	40	36
	Avg Purchased Demand (kWh/account	3,627	3,727	1,961	2,078	3,338	3,734	4,807	4,463	3,311	2,378	1,857	915
	Offsite Generation (kW)	37,045	42,153	20,031	21,932	34,101	39,417	49,104	45,587	34,946	24,289	19,604	9,343
	Total Onsite Solar Generation (kW)	385	457	539	618	609	603	596	583	554	501	426	367
Fixed	Avg Irradiance (kWh/m^2/day)	3.8	4.5	5.2	5.9	5.8	5.7	5.7	5.6	5.4	4.9	4.2	3.6
	Avg Irradiance (kWh/m^2/month)	118	126	161	177	180	171	177	174	162	152	126	112
	New Fixed Solar Generation (kWh)	159,030	170,100	217,620	238,950	242,730	230,850	238,545	234,360	218,700	205,065	170,100	150,660
	New Fixed Solar Generation (kW)	214	253	293	332	326	321	321	315	304	276	236	203
1-axis	Avg Irradiance (kWh/m^2/day)	4.5	5.4	6.6	7.7	7.6	7.6	7.4	7.2	6.7	6.0	5.0	4.3
	Avg Irradiance (kWh/m^2/month)	140	151	205	231	236	228	229	223	201	186	150	133
	New 1-axis Solar Generation (kWh)	120,319	130,410	176,468	199,238	203,205	196,650	197,858	192,510	173,363	160,425	129,375	114,971
	New 1-axis Solar Generation (kW)	162	194	237	277	273	273	266	259	241	216	180	155
	New Solar Generation (kWh)	279,349	300,510	394,088	438,188	445,935	427,500	436,403	426,870	392,063	365,490	299,475	265,631
	New Solar Generation (kW)	375	447	530	609	599	594	587	574	545	491	416	357
	Existing Solar Capacity (kW)	50	50	50	50	50	50	50	50	50	50	50	50
	Existing Solar Generation (kWh)	7,161	6,468	7,161	6,930	7,161	6,930	7,161	7,161	6,930	7,161	6,930	7,161
	Existing Solar Generation (kW)	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6
	Initial Retail Rate ($/kWh)	$0.0970	$0.0970	$0.0982	$0.0980	$0.1327	$0.1341	$0.1367	$0.1360	$0.1326	$0.1274	$0.0983	$0.1008
	Avg Wholesale Rate ($/kWh)	$0.0310	$0.0252	$0.0314	$0.0277	$0.0297	$0.0266	$0.0307	$0.0262	$0.0297	$0.0276	$0.0252	$0.0313
	Adjusted Retail Rate ($/kWh)	$0.0963	$0.0962	$0.0962	$0.0959	$0.1307	$0.1324	$0.1353	$0.1345	$0.1308	$0.1253	$0.0969	$0.0982
	Difference ($/kWh)	**($0.0007)**	**($0.0007)**	**($0.0020)**	**($0.0022)**	**($0.0020)**	**($0.0017)**	**($0.0014)**	**($0.0015)**	**($0.0017)**	**($0.0021)**	**($0.0015)**	**($0.0026)**

Table A3. Table showing the generation, capacity, and impact on retail electricity rates from the solar segment.

Panel Specifications	Capacity (kW)	Cost ($/W)*	Size (m^2)	Useful Life (yrs)	Performance Ratio	Capacity Factor
Fixed	750	$1.03	7,500	20	72.0%	25.0%
1-axis tracking	500	$1.11	5,000	20	75.0%	23.0%

New Solar	Cost			
Fixed Panel Cost	$772,500			
1-axis Panel Cost	$555,000			
Installation Costs	$50,000			
	$1,377,500	Total	**$8,676**	**Per Month**

Annual Rev	$750,903
Capital	($1,377,500)
Vp	$1,489,810
RoR	**8%**

Existing Solar	
Capacity (kW)	50
Performance Ratio	77.0%
Capacity Factor	25.0%

Table A4. Tables showing specifications, cost inputs, and rate of return for the solar segment.

Diesel Generators

Diesel Generation	January	February	March	April	May	June	July	August	September	October	November	December
Peak Demand (kW)	37,430	42,610	20,570	22,550	34,710	40,020	49,700	46,170	35,500	24,790	20,030	9,710
Peak Demand (kWh)	27,847,920	28,633,920	15,304,080	16,236,000	25,824,240	28,814,400	36,976,800	34,350,480	25,560,000	18,443,760	14,421,600	7,224,240
Avg Demand (kWh/account)	3,664	3,768	2,014	2,136	3,398	3,791	4,865	4,520	3,363	2,427	1,898	951
Avg Onsite Demand (kWh/account)	15	14	15	14	15	14	15	15	14	15	14	15
Ave Purchased Demand (kWh/account)	3,649	3,754	1,999	2,122	3,383	3,777	4,850	4,505	3,349	2,412	1,883	936
Offsite Generation (kW)	37,277	42,457	20,417	22,397	34,557	39,867	49,547	46,017	35,347	24,637	19,877	9,557
Total Onsite Diesel Generation (kW)	153	153	153	153	153	153	153	153	153	153	153	153
Avg Fuel Price ($/gal)	$2.580	$2.568	$2.554	$2.583	$2.560	$2.511	$2.496	$2.595	$2.785	$2.794	$2.439	$2.510
Fuel Consumption (gal)	210	189	210	203	210	203	210	210	203	210	203	210
Fuel Cost	$541	$486	$536	$524	$537	$510	$523	$544	$565	$586	$495	$526
New Diesel Capacity (kW)	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
New Diesel Generation (kWh)	58,032	52,416	58,032	56,160	58,032	56,160	58,032	58,032	56,160	58,032	56,160	58,032
New Diesel Generation (kW)	78	78	78	78	78	78	78	78	78	78	78	78
Existing Diesel Capacity (kW)	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
Existing Diesel Generation (kWh)	55,800	50,400	55,800	54,000	55,800	54,000	55,800	55,800	54,000	55,800	54,000	55,800
Existing Diesel Generation (kW)	75	75	75	75	75	75	75	75	75	75	75	75
Emissions (tCO2)	2.3	2.1	2.3	2.2	2.3	2.2	2.3	2.3	2.2	2.3	2.2	2.3
Carbon Price ($/tCO2)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Carbon Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Initial Retail Rate ($/kWh)	$0.0970	$0.0970	$0.0982	$0.0980	$0.1327	$0.1341	$0.1367	$0.1360	$0.1326	$0.1274	$0.0983	$0.1008
Peak Rate ($/kWh)	$0.1520	$0.0795	$0.1575	$0.1018	$0.1612	$0.1055	$0.1573	$0.1075	$0.6546	$0.1432	$0.1173	$0.2271
Adjusted Retail Rate ($/kWh)	$0.0973	$0.0973	$0.0986	$0.0985	$0.1328	$0.1342	$0.1368	$0.1361	$0.1327	$0.1276	$0.0989	$0.1017
Difference ($/kWh)	**$0.0003**	**$0.0003**	**$0.0005**	**$0.0005**	**$0.0001**	**$0.0001**	**$0.0001**	**$0.0001**	**$0.0001**	**$0.0002**	**$0.0005**	**$0.0009**

Table A5. Table showing the generation, capacity, and impact on retail electricity rates from the diesel generators segment.

Generator Component	Cost	Frequency		
Generator Cost ($/kW)	$650			
Total Generator Costs	$1,950,000			
Land Costs	$250,000			
Installation Costs	$75,000			
	$2,275,000	Upfront	**$14,027**	**Per Month**
O&M ($/kW/yr)	$15.00			
	$45,000	Per Year	**$3,750**	**Per Month**

New Specifications	
Total Generators	3
Capacity (kW/generator)	1,000
Useful Life (yrs)	20
Capacity Factor	52.0%
Efficiency (kWh/gal)	16.50
Emissions Rate (kgCO2/l)	2.60
Expected Utilization Rate	5.0%

Annual Rev	$353,954
Total Capital	($2,275,000)
Vp	$702,253
RoR	**-69%**

Existing Specifications	
Capacity (kW)	15,000
Capacity Factor	50.0%
Efficiency (kWh/gal)	16.50
Emissions Rate (kgCO2/l)	2.60
Utilization Rate	1.0%

Table A6. Tables showing specifications, cost inputs, and rate of return for the diesel generators segment.

Battery Storage

Battery Storage	January	February	March	April	May	June	July	August	September	October	November	December
Peak Demand (kW)	37,430	42,610	20,570	22,550	34,710	40,020	49,700	46,170	35,500	24,790	20,030	9,710
Peak Demand (kWh)	27,847,920	28,633,920	15,304,080	16,236,000	25,824,240	28,814,400	36,976,800	34,350,480	25,560,000	18,443,760	14,421,600	7,224,240
Avg Demand (kWh/account)	3,664	3,768	2,014	2,136	3,398	3,791	4,865	4,520	3,363	2,427	1,898	951
Avg Purchased Demand (kWh/account)	3,653	3,758	2,003	2,126	3,387	3,781	4,854	4,509	3,353	2,416	1,887	940
Total Avoided Demand (kW)	113	113	113	113	113	113	113	113	113	113	113	113
Total Avoided Demand (kWh)	83,700	75,600	83,700	81,000	83,700	81,000	83,700	83,700	81,000	83,700	81,000	83,700
Avg Avoided Demand (kWh/account)	11	10	11	11	11	11	11	11	11	11	11	11
New Avoided Demand (kW)	113	113	113	113	113	113	113	113	113	113	113	113
New Avoided Demand (kWh)	83,700	75,600	83,700	81,000	83,700	81,000	83,700	83,700	81,000	83,700	81,000	83,700
New Avoided Demand (kWh/account)	11	10	11	11	11	11	11	11	11	11	11	11
Current Avoided Demand (kW)	0	0	0	0	0	0	0	0	0	0	0	0
Current Avoided Demand (kWh)	0	0	0	0	0	0	0	0	0	0	0	0
Current Avoided Demand (kWh/account)	0	0	0	0	0	0	0	0	0	0	0	0
Initial Retail Rate ($/kWh)	$0.0970	$0.0970	$0.0982	$0.0980	$0.1327	$0.1341	$0.1367	$0.1360	$0.1326	$0.1274	$0.0983	$0.1008
Peak Rate ($/kWh)	$0.1520	$0.0795	$0.1575	$0.1018	$0.1612	$0.1055	$0.1573	$0.1075	$0.6546	$0.1432	$0.1173	$0.2271
Adjusted Retail Rate ($/kWh)	$0.0975	$0.0975	$0.0991	$0.0989	$0.1331	$0.1345	$0.1370	$0.1363	$0.1330	$0.1280	$0.0993	$0.1027
Difference ($/kWh)	**$0.0005**	**$0.0005**	**$0.0009**	**$0.0009**	**$0.0004**	**$0.0004**	**$0.0003**	**$0.0003**	**$0.0005**	**$0.0006**	**$0.0010**	**$0.0019**

Table A7. Table showing the avoided demand and impact on retail electricity rates from the battery storage segment.

Li-Ion Battery Component	Cost	Frequency		
Battery Cost ($/kWh)	$683			
Total Battery Costs	$2,049,000			
Land Costs	$100,000			
Installation Costs	$50,000			
	$2,199,000	Upfront	**$22,473**	**Per Month**
O&M ($/kWh)	$0.030			
	$89	Per Year	**$7**	**Per Month**

New System Specifications	
Total Units	2
Size (kW/battery)	500
Capacity (kWh/battery)	1,500
Avg System Efficiency	90.0%
Useful Life (yrs)	10

Annual Rev	$546,432
Capital	($2,199,000)
Vp	$1,076,411
RoR	**-51%**

Existing System Specifications	
Size (kW)	0
Capacity (kWh)	0
Efficiency	0.0%
Useful Life (years)	0

Table A8. Tables showing specifications, cost inputs, and rate of return for the battery storage segment.

Demand Response

Demand Response	January	February	March	April	May	June	July	August	September	October	November	December
Peak Demand (kW)	37,430	42,610	20,570	22,550	34,710	40,020	49,700	46,170	35,500	24,790	20,030	9,710
Peak Demand (kWh)	27,847,920	28,633,920	15,304,080	16,236,000	25,824,240	28,814,400	36,976,800	34,350,480	25,560,000	18,443,760	14,421,600	7,224,240
Avg Demand (kWh/account)	3,664	3,768	2,014	2,136	3,398	3,791	4,865	4,520	3,363	2,427	1,898	951
Avg Purchased Demand (kWh/account)	3,664	3,767	2,014	2,136	3,398	3,791	4,865	4,519	3,363	2,427	1,898	951
Total Avoided Demand (kW)	4.5	4.5	0.0	0.0	0.0	4.5	4.5	4.5	0.0	0.0	0.0	0.0
Total Avoided Demand (kWh)	3,340	3,017	0	0	0	3,233	3,340	3,340	0	0	0	0
Avg Avoided Demand (kWh/account)	0.4	0.4	0.0	0.0	0.0	0.4	0.4	0.4	0.0	0.0	0.0	0.0
New Avoided Demand (kW)	2.6	2.6	0.0	0.0	0.0	2.6	2.6	2.6	0.0	0.0	0.0	0.0
New Avoided Demand (kWh)	1,938	1,750	0	0	0	1,875	1,938	1,938	0	0	0	0
New Avoided Demand (kWh/account)	0.3	0.2	0.0	0.0	0.0	0.2	0.3	0.3	0.0	0.0	0.0	0.0
Current Avoided Demand (kW)	1.9	1.9	0.0	0.0	0.0	1.9	1.9	1.9	0.0	0.0	0.0	0.0
Current Avoided Demand (kWh)	1,403	1,267	0	0	0	1,358	1,403	1,403	0	0	0	0
Current Avoided Demand (kWh/account)	0.2	0.2	0.0	0.0	0.0	0.2	0.2	0.2	0.0	0.0	0.0	0.0
Initial Retail Rate ($/kWh)	$0.0970	$0.0970	$0.0982	$0.0980	$0.1327	$0.1341	$0.1367	$0.1360	$0.1326	$0.1274	$0.0983	$0.1008
Peak Rate ($/kWh)	$0.1520	$0.0795	$0.1575	$0.1018	$0.1612	$0.1055	$0.1573	$0.1075	$0.6546	$0.1432	$0.1173	$0.2271
Adjusted Retail Rate ($/kWh)	$0.0970	$0.0970	$0.0982	$0.0980	$0.1327	$0.1341	$0.1367	$0.1360	$0.1326	$0.1274	$0.0984	$0.1008
Difference ($/kWh)	($0.0000)	($0.0000)	$0.0000	$0.0000	$0.0000	($0.0000)	($0.0000)	($0.0000)	$0.0000	$0.0000	$0.0000	$0.0000

Table A9. Table showing the avoided demand and impact on retail electricity rates from the demand response segment.

Ecobee Thermostat Component	Count	Cost	Frequency		
Total New Thermostats	250	N/A			
Thermostat Cost (per unit)		$38			
Installation Costs (per unit)		$50			
		$21,875	Upfront	$94	Per Month
O&M		$1,000			
Replacement Parts		$250			
		$1,250	Per Year	$104	Per Month

New System Specifications	
Average Demand Avoided (kWh/day/thermostat)	0.25
Customer Payout ($/month)	$4.00
Useful Life (yrs)	40

Existing System Specifications	
Thermostats Installed	181
Customer Payout ($/month)	$4.00
Average Demand Avoided (kWh/day/thermostat)	0.25

Annual Rev	$1,728
Capital	($21,875)
Vp	$3,429
RoR	**-84%**

Table A10. Tables showing specifications, cost inputs, and rate of return for the demand response segment.